NON-PUBLIC?: N
ACCESSION #: 9011020052
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Brunswick Steam Electric Plant Unit 2 PAGE: 1 OF 11

DOCKET NUMBER: 05000324

TITLE: Unit 2 Reactor Scram Due to Erratic Voltage Regulator Response
EVENT DATE: 09/27/90 LER #: 90-015-00 REPORT DATE: 10/26/90

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: Tony Harris, Regulatory Compliance Specialist TELEPHONE: (919) 457-2038

COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On 9/27/90, while operating at 100% power, Unit 2 experienced generator voltage oscillations which resulted in a loss of the main generator due to loss of excitation. This resulted in a reactor scram due to control valve fast closure signal. The primary cause of the SCRAM was a voltage regulator that had become potentially unstable due to past improper adjustments.

Systems functioned as designed. Potential concerns were noted with a CRD that did not fully insert (02 position versus 00 position) and dual position indication on an MSIV. Cause of the SCRAM was inadequate configuration control on the voltage regulator adjustments and URAL circuit settings. Potentially contributing to the event was the grid system configuration on that date, the system voltage schedule, and procedural controls for maintaining generator excitation. Corrective actions include adjustments of the voltage regulator, updating the vendor technical manual to ensure proper future system performance, and

evaluations of the grid stability requirements and design basis relative to system capacitance values.

The event safety significance is considered minimal. Transient parameters experienced were well within analyzed transient parameters for this type event.

END OF ABSTRACT

EVENT

Unit 2 Reactor Scram of September 27, 1990, due to generator voltage oscillations.

INITIAL CONDITIONS

Unit 2 was operating under steady state conditions at 100% power. On 9/27/90, at 0539, problems were experienced with generator voltage oscillations which were thought to be the result of high temperatures affecting the operation of the automatic voltage regulator. Supplemental cooling was supplied to the regulator panel and the operation of the regulator stabilized; however, shortly thereafter, erratic operation of the voltage regulator was again noted. Problems were also experienced with the amount of VARS being generated, which also had been adjusted. Brunswick Unit 2 was the only unit on line within the Southeastern section of North Carolina. Increasing load demands were occurring during this time in accordance with anticipated daily system demand increases.

EVENT DESCRIPTION

On 9/27/90, at 0830, additional voltage swings were experienced on the plant electrical system. Voltage on buses E3 and E4 decreased to about 60% of normal (about 2500 volts) voltage for about 1.5 seconds. Emergency Response Facility Information System (ERFIS) data collection was affected during this voltage transient.

With the voltage swings being experienced on the plant electrical system, a generator loss of excitation relay trip was experienced, leading to a generator primary lockout. Lockout initiated an automatic reactor scram due to control valve fast closure signal, tripped the turbine, and

started Emergency Diesel Generators (EDG) 1, 2, 3, and 4. Control rods began to insert, shutting down the reactor. The following is a summary of the events resulting from the 9/27/90 voltage swings. The times referenced are from the plant process computer.

TIME EVENT

02:25 Unit 1 disconnected from grid for refueling outage.

05:40 System dispatcher added 18 Megavar capacitor bank at Eagle Island to CP&L system grid.

06:36 System dispatcher added 33 Megavar capacitor bank #3 at Delco to grid.

08:30:10 Voltage swings experienced on the plant electrical system. Voltage on buses E3 and E4 decreased to about 60% of normal for about 1.5 seconds. ERFIS data collection during this time period was affected.

Generator loss of excitation relay trip experienced leading to a generator primary lockout. Lockout initiated an automatic reactor scram due to control valve fast closure signal, tripped the turbine, and started EDGs 1, 2, 3, and 4. Control

rods began to insert, shutting down the reactor.

Undervoltage alarms were received on Main Transformer and Unit Auxiliary Transformer (UAT). Flags identified tripped breakers on 4KV buses 2B, 2C, and 2D. Recirculation Pump Motor-Generator (M-G) sets 2A and 2B, Conventional Service Water (CSW) pumps 1A, 2A, and 2B, Nuclear Service Water (NSW) pump 2B, Control Rod Drive (CRD) pump 2A, and fire pump alternate feed breaker tripped. No busses tripped. CSW pump 2C automatically started.

E-bus undervoltage resulted in Group 1 (Main Steam Line), Group 6 (CAC, Unit 1 only), Group 3B (RWCU outboard), and Group 10 pneumatic nitrogen system (PNS) to drywell! isolations due to the impact of the logic. MSIV's began to close, generating another scram signal. MSIV F028D indicated dual position following this isolation.

08:30:13 The decreased power generation and MSIV isolation collapsed the voids, lowering reactor level past low level 1, and increased reactor pressure. This caused additional reactor scrams from reactor low level and high pressure and isolated Group 2 Traversing In-core Probes (TIPS), floor drain, and sampling valves! and Group 6 (CAC) on Reactor Low Level 1.

08:30:15-16 Reactor level decreased to about 117" momentarily. Reactor Low Level 2 (LL2) received, starting High Pressure Coolant Injection (HPCI) system, Reactor Core Isolation Cooling (RCIC) system, and Standby Gas Treatment (SBGT) system, isolating secondary containment and Group 3A trip

system (RWCU inboard valve), and actuating Alternate Rod Injection (ARI) system.

08:30:18 Safety Relief Valves (SRVs) F013A (1105# setpoint) and F013B (1125# setpoint) open automatically to control the reactor pressure increase. Reactor pressure peaks at approximately 1112 psig.

08:30:24 Manual reactor scram inserted by operator as specified by the Emergency Operating Procedures (EOPs).

08:30:27 SRV F013A automatically closes.

08:30:29 RCIC began injecting water into the Reactor Pressure Vessel (RPV). HPCI remained on minimum flow due to the short duration of the LL2 condition.

08:30:42 SRV F013B automatically closes.

08:31:42 TIP detectors fully retracted and ball valves closed.

08:34:22 SRV F013F manually opened to control pressure.

SRV F013G (1105# setpoint) automatically opened momentarily.

08:34:34 Reactor feed pump 2B tripped on high level.

08:34:44 RCIC tripped on high reactor level. Level did not reach HPCI high level trip setpoint.

08:34:45 SRV F013F manually closed.

08:35:33 CRD Pump 2A restarted.

08:36:50 SRV F013E manually opened to control pressure.

08:37:00 Suppression Pool temperature increased above 95 degrees due to SRV openings.

08:37:38 SRV F013E manually closed.

08:37:40 RCIC manually started in level control.

08:38:50 Groups 1, 2, 3 and 6 isolation signals reset.

08:39:10 Manually initiated HPCI injection into the RPV for level control.

08:40:04 HPCI injection secured.

08:41:06-11 Outboard MSIVs reopened.

08:41:19 HPCI placed in pressure control mode.

08:43 Placed RHR loop 2B in torus cooling to remove heat from HPCI, RCIC, and SRV operation.

08:46 Placed RHR loop 2A in torus cooling to remove heat from HPCI, RCIC, and SRV operation.

08:52 RCIC tripped due to high reactor level.

08:53 Unusual Event declared due to failure of some 1105# SRV's to open.

08:57 Restored normal Reactor and Turbine Building ventilation.

09:00 Inboard MSIVs reopened.

Started RCIC in level control.

09:01 Received Group 1 on low condenser vacuum. MSIVs and B21-F016 closed as required, B21-F019 remained open as vacuum did not yet exceed setpoint of C & D channels.

09:04 Restored PNS to service.

09:05 Secured HPCI from pressure control.

09:08 Placed condenser low vacuum switch in bypass.

09:08-09:14 Secured Diesel Generators 1 and 2.

09:11-09:23 Pumped torus water to radwaste with RHR to reduce level from 27" to -29.5".

09:14 Reactor scram reset.

09:17 RCIC tripped on reactor high level.

CRD 34-27 identified in the 02 position.

09:19 Inserted control rod 34-27 to "00".

09:25-09:26 Secured Diesel Generators 3 and 4.

09:37 Started Mechanical Vacuum Pump to restore condenser vacuum.

RCIC started in pressure control.

09:40 Began equalizing around the MSIVs.

09:42 RCIC transferred to level control.

09:44 HPCI placed in pressure control.

09:50 HPCI secured.

10:01-10:03 MSIVs reopened on three steam lines (A, B, and C.)

10:02 HPCI restored to standby.

10:02 Unusual Event terminated.

EVENT CAUSE

This LER addresses the initiating cause of the SCRAM and the following resulting occurrences:

1. The multiple momentary plant electrical system voltage perturbations which resulted from the undervoltage condition.

2. The dual position indication on the 2-B21-F028D outboard MSIV.

3. SRV response during the event.

4. HPCI response during the event.

5. Control Rod 34-27 being found in the 02 position following the SCRAM.

6. Diesel Generator response during the event.

SCRAM Initiation

The SCRAM was a result of a generator load reject on a low voltage condition. Excessive system voltage swings on the voltage regulator just prior to the event resulted in a los of excitation of the generator, and the subsequent load rejection.

To assist in the investigation of the voltage regulator concerns, a vendor (General Electric) Technical Representative was requested.

Detailed research into past voltage regulator problems and component tests revealed that:

1. Configuration control on the system was lacking in past evolutions, even though vendor assistance was utilized. The regulator was initially put in service in 1976. Per factory recomendation, the automatic regulator gain was changed in 1979 by a GE Technical Representative. This change was later recommended in GE TIL No. 961. Maintenance activities following regulator problems in 1985 resulted in voltage regulator adjustments being outside of preferred settings, although the work was performed under the guidancce of the vendor technical representative. Subsequently, a voltage regulator that may become unstable duration operation was created.

2. Underexcited Reactive Ampere Limit (URAL) circuit settings were not compatible with existing automatic (AC) regulator settings. This condition could have created an unstable voltage regulator if the URAL setpoint was reached during operation.

3. The Electrical system grid configuration on 9/27/90, along with inadequate plant control of generator excitation, potentially contributed to the stability problems with the voltage regulator. Specifically, the following conditions were noted:

a. Generator field voltage swings were noticed prior to the SCRAM. The voltage swings began when system capacitor banks (used for degraded voltage enhancement) were closed in by system operations. The system grid voltage had

increased due to capacitor addition, which resulted in the generator operating at unity or leading power factor (weak field).

b. The Control Room procedure for maintaining generator excitation did not require a strong field be maintained (>20 megavars out); however, at the time of the scram, a check of the megavar integrator showed the plant operating in a megavars out condition.

c. The system voltage schedule and degraded voltage requirements (i e. capacitors) conflicted with maintaining a strong field while the system load was light.

The combination of the above factors resulted in the unstable system

operation of 9/27/90, leading to an undervoltage condition on the generator and subsequent load rejection; however, the main factor involved in the SCRAM was determined to be improper voltage regulator adjustments.

Plant Electrical System Perturbations

The generator load reject initiated a CP&L system voltage reduction transient that was greatest at the Brunswick site. Transmission oscillograph traces for this event showed a generator voltage drop to approximately 58%. The voltage drop was not an abrupt loss, but a gradual loss of voltage that did not decrease below 58%. The

momentary undervoltage condition resulted in miscellaneous relay initiations. These type initiations could be expected, in that past experience has indicated that voltages in the 60% to 70% range have resulted in some normally energized AC relays dropping out.

As a result of the undervoltage condition, undervoltage alarms were received on the plant process computer at the beginning of the event. The alarms were initiated from the 27/59E relays on buses E3 and E4. These relays initiated load shedding on both bus E3 and E4. The feeders to the 2B NSW pump, the 1A, 2A and 2B CSW pumps, and the 2A CRD pump tripped as a result of load shedding response. The Alternate Fire Pump feeder also tripped. The Unit 2 pump trips alarmed on the Unit 2 process computer log. No evidence was retrievable for the Unit 1A CSW pump trip; however, subsequent investigation indicated that the pump tripped in accordance with design. Other targets were received during the event on the 27/59U relays at the 4KV 2B| 2C, and 2D buses. These were expected or anticipated targets due to the generator trip.

The undervoltage event lasted approximated 5-6 seconds, and was not of sufficient duration or depth to actuate the 27DV relays and result in separation of the Emergency buses from the BOP buses. The Caswell Beach pumping station was being fed from Unit 1 and the resulting undervoltage condition was not severe enough to result in loss of the Caswell Beach feed.

MSIV F028D Dual Position Indication

Work Request/Job Order (WR/JO) 90-AQZI1 was initiated to investigate the reason for the transitory dual indication on the F028D MSIV.

Prior to troubleshooting initiation, the dual signal indication had cleared in the Control Room. Troubleshooting found the valve full stroking from full open to the full closed position, with proper indication in the Control Room. Further investigation found no problems with the indication.

SRV Response

As noted in the Event Sequence, SRVs F013A and F013B opened automatically to reduce reactor pressure as a result of this event. SRV F013B opened approximately .3 seconds after SRV F013A. SRV F013A has a Technical Specification lift setpoint requirement of 1105 psig 1%. SRV F013B has a Technical Specification lift setpoint of 1125 psig 1%. Since only one 1105 setpoint SRV and one 1125 setpoint SRV automatically lifted for this

event, a concern was present about SRV operation for the SCRAM. As a result, during SCRAM recovery, enough uncertainty existed during the SCRAM recovery to make a conservative decision to declare an Unusual Event due to other SRV's not functioning properly. Initial and follow-up notifications were subsequently made.

A review was conducted by the Technical Support Unit for the SRV operation during this event. The review concluded:

1. The peak pressure of approximate 1113 psig for this event was just above the "as-left" lift point for one of the 1105 psig setpoint SRVs (F013A). The other 1105 psig setpoint SRV's

(F013C, F, and G) had as-left setpoints very similar to the F013A (within 1 psig). Since peak pressure was just above the as-left setpoints, any of the 1105 setpoint SRVs could have responded first without the other 1105 SRVs lifting. Once SRV F013A lifted, enough pressure was relieved to drop system pressure below the minimum setpoints.

2. SRVs F013A and F013B will provide pressure relief off main steam line A. When the F013A SRV lifted, it caused a predictable transient in the steam line, resulting in the momentary opening of the F013B SRV. A similar steam line transient appears to have caused the F013G SRV to open in response to the manual initiation of SRV F013F (SRVs F013F and F013G provide pressure relief for main steam line C).

3. Single line dominance for SRVs has been seen numerous time at Brunswick. As a result, SRV response to this incident is considered to be as expected.

HPCI Event Response

At 08:31 during the event, HPCI auto started but did not auto inject. This is an expected response due to the short duration (< 5 seconds) of the LL2 (118"-trip, 122"-reset) initiation signal. HPCI operated for 8.5 minutes in the minimum flow mode, until the injection valve was manually opened for reactor level recovery. In the 1 minute that HPCI injected, it recovered level from 170" to 195". The injection valve was closed and, after 1.1 minutes of minimum flow, HPCI was placed in the pressure control mode. HPCI was manually secured 35 minutes after the system auto started. HPCI

was later manually placed in pressure for 7 minutes. Review of data for this event determined that the system performed as expected with no problems noted. It should be noted that HPCI operated for 42 minutes with no evidence of water intrusion into the lube oil system. Post operation sampling indicated results consistent with normal standby conditions.

Control Rod 34-27 Found in the
2 Position

Following the SCRAM, Control Rod 34-27 was noted in the 02 position. Control Rods in the 02 position following a SCRAM is usually indicative of leakage of the stop piston seals in and around the buffer zone of the stop piston due to normal wear. As a result, the control rod would not insert far enough to latch in the 00 position, and would drift and latch into the 02 position. The Control Rod was then manually inserted to the full-in 00

position. A Control Rod underpiston flush and interference testing was performed in accordance with Operating Procedure (OP)-07. The testing was completed satisfactorily prior to startup.

Diesel Generator Response During the Event

The Unit 2 generator tripped via the loss of excitation relay, device 40-1. The 40-1 relay actuation resulted in actuation of the generator primary lockout relays 86GP1-2 and 86GP2-2. The 86GP2-2 lockout initiated diesel generator starts for all 4 diesel

generators. ERFIS data traces of the 4KV E bus voltages and the diesel generator voltages revealed the diesel generators started and came to normal voltage (approximately 4KV) within 10 seconds of the voltage perturbation on the 4KV E buses. The generator voltages were DG1-3809V, DG2-4475V, DG3-4330V, and DG4-4181V. These were within the acceptable generator voltage range of 10% of 4160V (3744V to 4576V). The diesel generators did not tie-on to the emergency buses because normal power was not lost or degraded for sufficient duration.

CORRECTIVE ACTIONS

With assistance of the vender representative, the Voltage regulator and URAL circuitry were set in accordance with the vendor technical manual and GE TIL 961. On 10/1/90, the unit was started up, the main generator rolled to rated speed, and voltage regulation system checks were made in accordance with the vendor technical manual. A startup action item required additional on-line checks to be performed prior to exceeding 200 MW, and maintaining the active load below reactor trip setpoint for turbine trips. On 10/2/90, the system near the unit was subjected to multiple switching of megavar loads, with the regulator operation to be satisfactory.

A Standing Instruction (90-090) has been issued to provide operator guidance for operation of the main generator voltage regulation. This guidance is to be incorporated into the plant operating procedures.

The vendor technical manual for the excitation system is being updated, to ensure that future system maintenance is performed in accordance with the latest vendor recommendations.

System dispatcher and plant voltage schedule and MVAR requirements for lightly loaded and heavily loaded grid conditions will be reviewed to determine if existing added capacitance values are adequate. An evaluation will also be performed regarding grid stability requirements and design basis accidents to ensure the requirements are adequately maintained.

WR/JO 90-ASXP1 has been initiated to monitor CRD 34-27 response during the remainder of the fuel cycle. Current plans are to rebuild CRD 34-27 during the next refuel outage.

Further assessment of SRV response during this event has determined that SRVs did function as expected, and that no Unusual Event declaration was necessary. The NUREG guidance for determining SRV failure involves Reactor Pressure indications versus SRV operation. This gives a more accurate indication of SRV failure.

BSEP has revised its Emergency Action Levels (EALs) and flowcharts to more accurately reflect the NUREG guidance for determining SRV failures in order to eliminate unnecessary emergency declaration and provide a more accurate indication of potential SRV failure.

No further corrective actions are considered necessary for items 1, 2, 4, and 6 above.

EVENT ASSESSMENT

The overall safety significance of this event was minimal. The generator load reject is an analyzed transient with initial power analyzed at 105%. Transient parameters for this event were well within the analyzed generator load reject transient parameters for BSEP. Equipment operated as expected. The electrical perturbations, HPCI, EDG, and SRV system responses discussed above were as expected, with no negative impact on the event. The dual position indication experienced on MSIV F028D had minimal safety significance, as the valve did close as expected. The Control Rod drive (34-27) in the 02 position had minor safety significance relative to the Technical Specification required Shutdown Margin. Emergency Operating Procedure bases evaluate that both Brunswick reactors would be shutdown if all control rods are inserted to position 02 or further after a SCRAM. In addition, the 34-27 CRD did fully insert during current fuel cycle SCRAMS on 8/16/90, 8/19/90, and 8/30/90, and a subsequent SCRAM on 10/12/90.

BSEP 1990 SCRAMS have been reported in LERs 2-90-04, 2-90-08, 2-90-09, 2-90-12, 2-90-16, and 1-90-17. Causal factors are evaluated in each of these reports. No other 1990 SCRAMs involved voltage regulator problems. The last SCRAM reported relative to the voltage regulator was reported in LER 1-87-19, during trouble shooting on the voltage regulator.

EIIS CODES

SYSTEM/COMPONENT CODE

EDG System EK
ERFIS ##

Main Generator TB
UAT EL
CSW KG
NSW BI
CAC BB
RWCU CE
PNS ##
MSIV SB/ISO
TIP IG
SBGT BH
SRV ##
RCIC BN
HPCI BJ
PCIS JE
Control Rod Drive System AA
Mechanical Vacuum Pump SH/P
Voltage Regulator TL/RG
URAL TL/61
Capacitor Banks EL/CAP
Alternate Fire Pump KP/P

No EIIS System Code Available

CP&L

Carolina Power & Light Company

Brunswick Nuclear Project

P. O. Box 10429
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October 26, 1990

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SERIAL: BSEP/90-0735

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

BRUNSWICK STEAM ELECTRIC PLANT UNIT 2
DOCKET NO. 50-324
LICENSE NO. DRP-62
LICENSEE EVENT REPORT 2-90-015

Gentlemen:

In accordance with Title 10 of the Code of Federal Regulations, the enclosed Licensee Event Report is submitted. This report fulfills the requirement for a written report within thirty (30) days of a reportable occurrence and is submitted in accordance with the format set forth in NUREG-1022, September 1983.

Very truly yours,

J. L. Harness, General Manager
Brunswick Nuclear Project

TH/th

Enclosure

cc: Mr. S. D. Ebneter
Mr. N. B. Le
BSEP NRC Resident Office

ATTACHMENT 1 TO 9011020052 PAGE 2 OF 2

BSEP/90-0735 -2-

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